PB85-245330

Status of Commercial Utility FGD (Flue Gas Desulfurization) Technology

(U.S.) Environmental Protection Agency
Research Triangle Park, NC

Jul 85

U.S. Department of Commerce
National Technical Information Service
NTIS

TECHNICAL REPORT DATA
(Please read Instructions on the reverse before completing)

1. REPORT NO. EPA/600/D-85/155	2.
3. RECIPIENT'S ACCESSION NO. PB85 245330/AS	
4. TITLE AND SUBTITLE Status of Commercial Utility FGD Technology	5. REPORT DATE July 1985
	6. PERFORMING ORGANIZATION CODE
7. AUTHOR(S) Norman Kaplan	8. PERFORMING ORGANIZATION REPORT NO.
9. PERFORMING ORGANIZATION NAME AND ADDRESS See Block 12	10. PROGRAM ELEMENT NO.
	11. CONTRACT/GRANT NO. 68-02-3173, Task 93
12. SPONSORING AGENCY NAME AND ADDRESS EPA, Office of Research and Development, Air and Energy Engineering Research Laboratory, Research Triangle Park, NC 27711	13. TYPE OF REPORT AND PERIOD COVERED Published paper; 10/83
	14. SPONSORING AGENCY CODE EPA/600/13

15. SUPPLEMENTARY NOTES AEERL project officer is Norman Kaplan, Mail Drop 61, 919/541-2556.

16. ABSTRACT The paper summarizes the status of FGD technology as of March 1983 and highlights recent trends in process selection, design, and performance of FGD systems. Current data for domestic FGD systems show 106 systems in operation, 35 systems under construction, and 70 systems planned. The current FGD-controlled capacity in the U.S. is 41,894 MW. At present about 15 percent of the total coal-fired capacity is controlled by FGD systems. Current projections indicate that total power generating capacity of the U.S. electric utility industry will be about 799 GW by the end of 1991. About 352 GW, or 44 percent of the 1991 total, will come from coal-fired units. About 34 percent of the projected 1991 coal-fired capacity will be controlled by FGD systems. The information collected in this program is stored in the Flue Gas Desulfurization Information System (FGDIS), a collection of computerized data base files containing descriptive, design, performance, and cost data for all the FGD systems identified in FGDIS.

17. KEY WORDS AND DOCUMENT ANALYSIS

a. DESCRIPTORS	b. IDENTIFIERS/OPEN ENDED TERMS	c. COSATI Field/Group
Pollution Flue Gases Desulfurization Coal Combustion Utilities Electric Power Generation	Pollution Control Stationary Sources	13B 21B 10A 07A, 07D 21D

18. DISTRIBUTION STATEMENT Release to Public	19. SECURITY CLASS (This Report) Unclassified	21. NO. OF PAGES 31
	20. SECURITY CLASS (This page) Unclassified	22. PRICE $9.95

EPA Form 2220-1 (9-73)

NOTICE

This document has been reviewed in accordance with U.S. Environmental Protection Agency policy and approved for publication. Mention of trade names or commercial products does not constitute endorsement or recommendation for use.

PB85-245330

EPA/600/D-85/155
July 1985

STATUS OF COMMERCIAL UTILITY FGD TECHNOLOGY

by

Norman Kaplan

Industrial Environmental Research Laboratory
U.S. Environmental Protection Agency
Research Triangle Park, North Carolina 27711

Air and Energy Engineering Research Laboratory
Office of Research and Development
U.S. Environmental Protection Agency
Research Triangle Park, NC 27711

REPRODUCED BY
NATIONAL TECHNICAL
INFORMATION SERVICE
U.S. DEPARTMENT OF COMMERCE
SPRINGFIELD, VA. 22161

ABSTRACT

This paper summarizes the status of FGD technology as of March 1983 and highlights recent trends in process selection, design, and performance of FGD systems. Current data for domestic FGD systems show 106 systems in operation, 35 systems under construction, and 70 systems planned. The current FGD-controlled capacity in the United States is 41,894 MW. At present approximately 15 percent of the total coal-fired capacity is controlled by FGD systems. Current projections indicate that total power generating capacity of the U.S. electric utility industry will be approximately 799 GW by the end of 1991. Approximately 352 GW, or 44 percent of the 1991 total, will come from coal-fired units. Approximately 34 percent of the projected 1991 coal-fired capacity may be controlled by FGD systems.

PEDCo Environmental has been monitoring and reporting on the status of utility flue gas desulfurization (FGD) technology since 1974. During the period of 1974 to 1982, this effort was supported by the U.S. Environmental Protection Agency (EPA) under the direction of the Industrial Environmental Research Laboratory, Research Triangle Park. Starting this year, this effort is now jointly sponsored by EPA and the Electric Power Research Institute (EPRI). Project direction from EPRI is provided by the Coal Combustion Systems Division.

Information for this program is obtained by visits to plants having operational FGD systems and through regular contacts with the owner/operator utilities who are presently operating or planning FGD installations. Supplemental information is also solicited from FGD system and equipment suppliers, design/engineering firms, research organizations, and regulatory agencies.

The information collected in this program is stored in the Flue Gas Desulfurization Information System (FGDIS), which is a collection of computerized data base files containing descriptive, design, performance, and cost data for all the FGD systems identified in FGDIS.

TECHNOLOGY OVERVIEW[1]

BACKGROUND

The current environmental driving force for SO_2 emissions control is the Clean Air Act, amended in 1977, which created a schedule to decrease SO_2 emissions from power plants and other major sources for both new and existing facilities. The current New Source Performance Standard (NSPS) calls for 70 to 90 percent SO_2 emission reduction from all new coal-fired facilities with the higher level of reduction associated with high-sulfur coal. In no case can emissions of 520 Ng/J (1.2 lb $SO_2/10^6$ Btu) be exceeded. This mandates application of control technology to new utility boilers burning both high- and low-sulfur coal.

These standards apply to power plants for which construction or modification commenced after September 19, 1978, and are based on commercially available technology taking into account cost. Coal-fired steam generators whose construction or modification commenced after August 17, 1971, but before September 19, 1978, are subject to NSPS requiring maximum SO_2 emissions of 520 Ng/J (1.2 $lb/10^6$ Btu) but no percentage removal requirements.

The Clean Air Act amendments indirectly provide for regulation of existing power plants because State Implementation Plans (SIPs), required for each state, include a control strategy for ensuring maintenance of the promulgated ambient air quality standards for SO_2 and other regulated pollutants. To meet the ambient SO_2 standards, it is necessary to limit the emissions of existing power plants in many of the 247 air quality control regions in many of the states.

ALTERNATIVES FOR FGD

Within the next 5 years, the following options can provide for SO_2 control for coal-to-electricity systems: utilization of naturally occurring low-sulfur coal, physical coal cleaning, and FGD. In addition to these established technologies, limestone injection multistage burners (LIMB) may become a viable retrofit technology before 1990.

In addition, the following emerging technologies are in the development stage and may play a significant role in the post-1990 period: fluidized-bed combustion (atmospheric and pressurized), coal gasification, and coal liquefaction.

Naturally occurring low-sulfur coal is the most straightforward control option. Unfortunately, projected production capacity is limited, and most low-sulfur coal reserves are in the West, far from Midwestern and Eastern areas of demand. Utilization of low-sulfur coal east of the Mississippi leads to substantial transportation costs, yielding overall power production costs comparable to the use of FGD with local high-sulfur coals. Also, the current utility NSPS precludes the use of low-sulfur coal without additional sulfur removal in light of the aforementioned 70 to 90 percent control requirement.

Physical coal cleaning utilizes differences in physical properties (e.g., specific gravity) between inorganic pyritic sulfur and other coal constituents: coals vary widely in pyritic content (from about 20 to 80 percent of the total sulfur content); organic sulfur and sulfate comprise the remaining portion of the sulfur. Coal cleaning technology is relatively simple and low in both capital cost and annual revenue requirements. Up to 80 percent of the pyritic sulfur can be removed by physical removal techniques. As with naturally occurring low-sulfur coal, coal cleaning cannot generally be utilized alone to meet the current NSPS percentage removal requirements. It should be noted that the combination of coal cleaning and FGD can substantially lower costs compared to FGD alone for certain applications.

In light of the limitations of current low-sulfur coal and coal cleaning options, FGD technology provides the only means of control of new utility sources, inasmuch as it is the only option commercially available by which it is possible to reduce SO_2 emissions sufficiently to comply with the current NSPS promulgated under the Clean Air Act. However, for less stringent control requirements for certain existing sources, low sulfur coal and coal cleaning are viable options.

HISTORICAL DEVELOPMENT

The first commercial application of FGD to a power plant was in the U.K. in the early 1930s. The Battersea A power plant (228 MW) of the London Power Co., London, U.K., began flue gas washing in 1933. The process utilized wet scrubbing with alkaline Thames River water. The spent liquor was discharged back into the Thames after removal of solids and oxidation. The FGD system operated successfully at up to 95 percent SO_2 removal efficiency until the Battersea A power plant closed down in 1975. A similar FGD system operated on the Battersea B power plant (245 MW)

between 1949 and 1969, when FGD operation was temporarily suspended because of adverse effects on the Thames water quality.

The ICI Howden process, also developed in the U.K., was developed to avoid discharging scrubber effluent into the Thames. This technology was the precursor to current lime and limestone wet scrubbing technology in wide use today. The waste sludge produced was barged to sea for disposal. This process was applied to the Swansea power plant in 1935 and the Fulham power plant in 1937. These systems operated successfully until early World War II, when they were shut down since the steam plumes marked easy targets for enemy bombers.

The next FGD unit was installed at the Electrolytic Zinc Co. in Tasmania in 1949. Tidal water was used there as the absorbent for SO_2 from smelter gas.

In 1952 the first unit of the new oil-fired Bankside Power Station in London, U.K., was commissioned. The FGD system installed on this unit represented an improved version of the Battersea systems, using water from the Thames. This system, which had a 98 percent removal efficiency and capacity of 240 MW, was recently retired.

The 1950s and 1960s were a time of laboratory and pilot plant investigations of new processes. During the 1950s, the Tennessee Valley Authority (TVA) (U.S.) experimented with lime and limestone scrubbing systems, both dry and wet, and dilute acid processes; in Germany the first major carbon adsorption processes were developed. During the 1960s, the magnesium oxide, copper oxide, and sulfite scrubbing processes were investigated.

Lime/limestone processes were installed in 1964 on an iron ore sintering plant in the USSR and on a large sulfuric acid plant in Japan in 1966.

In 1966 Combustion Engineering developed a process which injected dry limestone into the boiler followed by a wet scrubbing operation. In the U.S., the first commercial system of this type was intalled in 1968; there were five utility installations of this system by 1972. Because of major problems associated with dry limestone injection, these systems proved inadequate. Problems included plugging (especially of the spaces between boiler tubes), low SO_2 removal, and increased particle emissions from the ESP's. The five installations are now either shut down or converted to other types of systems. U.S. lime and limestone FGD technology was substantially improved and advanced via the EPA prototype alkali scrubbing test facility at TVA's Shawnee Steam Plant. This facility identified scrubber configurations and operating parameters yielding reliable and efficient operation.

FGD has been widely used in Japan. Over 1,300 commercial FGD units have been operated to treat gases generated from various processes including many oil-fired boilers. FGD processes treat a total capacity of over 120,000,000 Nm^3/hr (40,000 MW equivalent).

The total capacity of coal-fired utility boilers in Japan is approximately 4,300 MW (3.7 percent of total utility power) and is expected to reach 10,000 MW (5.6 percent) in 1985 and 22,000 MW (10 percent) in 1990. Several coal-fired industrial boilers also may be constructed in the future. All of these boilers will apply FGD to reduce SO_2 emissions.

Recently, in the United States, dry scrubbing systems employing spray dryers and producing a dry disposable waste are becoming an important part of the U.S. market. Pilot, prototype, and large-scale demonstrational testing and early commercial operation have indicated that such systems can achieve up to 90 percent sulfur control (although most are designed for 70-80 percent control) at costs substantially lower than wet systems for low to medium sulfur coals.

DESCRIPTION OF FGD SYSTEMS

FGD systems can be classified in two general categories: (1) systems in which the sulfur product generated through a scrubbing or adsorption operation is disposed of as waste (throwaway product systems) and (2) those in which the sulfur product, such as sulfuric acid, is marketed (salable product systems). Although over 50 processes have been tested at bench scale or larger, the number of commercially significant processes is considerably smaller. The following commercially offered throwaway and salable product systems are considered the most important for near-term (through 1990) SO_2 control:

1. Throwaway product systems - lime and limestone scrubbing (both sludge and gypsum variations, wet and dry) and dual (double) alkali.

2. Salable product systems - magnesium oxide scrubbing and sodium sulfite scrubbing (Wellman-Lord).

Other potentially important systems which are under investigation include seawater scrubbing, carbon adsorption, and copper oxide adsorption. Tables 1, 2, and 3 categorize the important systems as "throwaway;" salable product, gypsum; and salable product, regenerative, respectively, and summarize their commercial status and principles of operation.

TABLE 1. SUMMARY DESCRIPTION OF FGD PROCESSES - "THROWAWAY" CATEGORY

FGD process (year of first use)	Primary reagent	Product of disposal	Operating principles	Present status
Limestone/sludge[a] (1933)	$CaCO_3$	$CaSO_3/CaSO_4$ wet sludge	Flue gases scrubbed with limestone slurry; SO_2 reacts to form insoluble Ca compounds which are separated and partly dewatered for disposal.	Commercial operation (coal and oil), principally in U.S.
Lime/sludge[a] (1972)	CaO	$CaSO_3/CaSO_4$ wet sludge	Flue gases scrubbed with slurry of hydrated lime; SO_2 reacts to form insoluble Ca compounds which are separated and partly dewatered for disposal.	Commercial operation (coal and oil), principally in U.S.
Dual (double) alkali/sludge (1974)	CaO ($CaCO_3$) and Na_2CO_3 (NaOH)	$CaSO_3/CaSO_4$ wet sludge	Flue gases scrubbed with alkaline Na compounds in solution; used solution regenerated with lime or limestone in separate reactor and to form insoluble Ca compounds which are separated and partly dewatered for disposal.	Commercial operation on coal-fired boilers in U.S.
Seawater scrubbing (1975)	Seawater	Dilute sulfite solution	Flue gases scrubbed with seawater on a once-through system and discharged back to sea.	Commercial small-scale operation on oil-fired boilers in Norway.

(Continued)

TABLE 1 (Continued)

FGD process (year of first use)	Primary reagent	Product of disposal	Operating principles	Present status
Dry scrubbing (1981)	CaO or sodium alkali	$CaSO_3$ or Na_2SO_3	Flue gases are treated in a spray dryer where alkali slurry or solution spray absorbs the SO_2, cools the flue gases, and produces a dry waste material collected in a downstream baghouse or electrostatic precipitator.	Several industrial and utility applications in construction and early operational phase. Currently applicable to coals with low to moderate sulfur content.
Sodium carbonate scrubbing (1974)	Na_2CO_3 or other alkali sodium salt	Na_2SO_3/ Na_2SO_4	Flue gases are treated in scrubber with sodium salt solution; spent liquor generally disposed of in evaporation ponds in arid areas.	Commercial in Western U.S. in arid areas where evaporation ponds feasible.

[a] Important variations of these processes are lime/alkaline fly ash and limestone/alkaline fly ash which utilize natural alkalinity in certain coals to greatly minimize reagent requirements; and use of small amounts of organic dibasic acid to buffer wet limestone slurry absorbents and thus improve performance.

TABLE 2. SUMMARY DESCRIPTION OF FGD PROCESSES - SALABLE PRODUCT, GYPSUM CATEGORY

FGD process (year of first use)	Primary reagent	Product of disposal	Operating principles	Present status
Limestone/gypsum (1973)	$CaCO_3$	Gypsum	Flue gases scrubbed with limestone slurry; resulting calcium-sulfur compounds are air-oxidized to gypsum, separated, and dewatered.	Commercial operation (coal and oil), principally in Japan
Lime/gypsum (1964)	CaO	Gypsum	Flue gases scrubbed with slurry of hydrated lime; resulting calcium-sulfur compounds are air-oxidized to gypsum, separated, and dewatered.	Commercial operation (coal and oil), principally in Japan, but also recently in West Germany.
Dual (double) alkali/sludge (1973)	NaOH or Na_2CO_3 and CaO or $CaCO_3$	Gypsum	Flue gases scrubbed with alkaline Na compounds in solution; used solution regenerated with lime or limestone in separate reactor and the insoluble calcium-sulfur compounds then air-oxidized to gypsum, separated, and dewatered.	Commercial operation on oil-fired boilers in Japan.
Dilute sulfuric acid/gypsum (Chiyoda) (1972)	H_2SO_4 and $CaCO_3$	Gypsum	Flue gases are scrubbed with dilute sulfuric acid containing ferric ion catalyst; air oxidation produces more sulfuric acid when bled off and neutralized with limestone; the gypsum is separated and dewatered.	Commercial operation on oil-fired boilers in Japan.

TABLE 3. SUMMARY DESCRIPTION OF FGD PROCESSES - SALABLE PRODUCT, REGENERATIVE CATEGORY

FGD process (year of first use)	Primary reagent	Product of disposal	Operating principles	Present status
Sodium sulfite (Wellman-Lord) (1971)	Na_2CO_3	SO_2	Flue gases are scrubbed with sodium sulfite solution, and the resulting sodium bisulfite is thermally regenerated to sodium sulfite and SO_2; the SO_2 is then further treated to marketable products.	Commercial operation on oil-fired boilers in Japan; also commercial application on coal-fired boilers in U.S.A.; also on chemical/oil refinery plants.
Magnesium oxide (1972)	MgO	SO_2	Flue gases scrubbed with slurry of hydrated magnesium oxide; insoluble magnesium sulfite is separated and calcined for recycle of MgO and regeneration of SO_2 for further treatment.	Commercial operation on oil-fired boilers in Japan; demonstration plant on coal-fired boiler in U.S.
Carbon adsorption (1974)	C	SO_2	SO_2 from flue gases is adsorbed on active carbon which is then regenerated thermally, releasing SO_2 for recovery.	Demonstration.
Copper oxide (Shell) (1973)	CuO	SO_2	SO_2 from flue gases is adsorbed on copper oxide coated alumina; this is then treated chemically to regenerate the adsorbent and produce SO_2 for the recovery.	Demonstration.

PROGRAM OVERVIEW

For approximately a decade, the U.S. Environmental Protection Agency (EPA) has monitored and reported on the development and growth of flue gas desulfurization (FGD) technology for fossil fuel fired utility boilers in the United States through contracts with PEDCo Environmental, Inc. From 1974 to 1982, this program was conducted by the EPA's Industrial Environmental Research Laboratory at Research Triangle Park, N.C. In 1983, EPA and the Electric Power Research Institute (EPRI) made arrangements to jointly sponsor the program, and future reports will be issued by EPRI.

The overall objective of the program still remains the same: to provide an objective and current perspective of FGD technology as applied to fossil fuel fired utility boilers and facilitate, through information dissemination, improvements in system design, performance, and costs for present and future facilities.

All information gathered for this program is housed in a computerized database called the Flue Gas Desulfurization Information System (FGDIS), which is maintained at the National Computer Center (NCC) at Research Triangle Park, N.C.

The design data contained in FGDIS encompass the entire emission control system and the power-generating unit to which it is applied. Descriptions include location, standards limiting emissions of SO_2 and particulate matter, power-generating capacity, boiler and stack information, average fuel analyses, and other general data. Input of design data specific to FGD systems ranges from general information such as process type, system supplier, and initial system startup date to more specific component design information and operating parameters such as absorber type, gas and liquid flow rates, and pressure drop. Also included in the data are descriptions of the methods of solids concentrating and waste disposal, flue gas reheat, and mist elimination, and information on capital costs and annual revenue requirements of FGD systems.

For operational FGD systems, FGDIS stores comprehensive performance data, including monthly dependability parameters and the service times from which they are calculated. Where available, actual system SO_2 and particulate matter removal efficiencies are included (and qualified). Problems encountered with

system operation and solutions implemented to correct them are coded and described. The performance of the FGD-equipped boiler is described in terms of service time, production (kWh), and capacity factor.

In addition to being used to generate a quarterly report, FGDIS is also available for direct on-line access. This important function not only provides interested parties with an opportunity to examine data that are too specific for convenient inclusion in the quarterly report, but it also provides immediate access to information that has been loaded into the system but not yet published (i.e., information that has become available during the period between quarterly reports). Information is gathered, reduced, verified, and loaded into the FGDIS on a continual basis to ensure that the files remain current.

Access to the FGDIS data files and management of these data are accomplished via a computer software package known as System 2000 developed by the Intel Corporation. This comprehensive data base management system offers extensive data retrieval capabilities. The set of user-oriented commands provided are flexible enough to satisfy virtually any information need. Utilization of system functions (average, standard deviation, summation, maximum value, minimum value) can be used to analyze the numerical data in the files. In addition, the data requested through the available commands can be selectively limited by a set of criteria included in the commands. This feature facilitates examination of design or performance parameters for a specific unit or a specific process type, and so on. The retrieval and analytical possibilities are limited only by the needs and imagination of the user.

STATUS AND GROWTH TRENDS OVERVIEW

STATUS

Table 4 summarizes the status of FGD systems in the United States as of the end of March 1983.

TABLE 4. NUMBER AND TOTAL CAPACITY OF FGD SYSTEMS[2]

Status	No. of units	Total controlled capacity, MW[a]	Equivalent scrubbed capacity, MW[b]
Operational	106	41,894	38,524
Under construction	35	17,408	16,932
Planned:			
Contract awarded	21	13,614	13,506
Letter of intent	8	6,560	6,560
Requesting/evaluating bids	6	3,400	3,400
Considering only FGD systems	35	20,343	20,165
TOTAL	211	103,219	99,087

[a]Summation of the gross unit capacities (MW) brought into compliance by the use of FGD systems regardless of the percentage of the flue gas scrubbed by the FGD system(s).

[b]Summation of the effective scrubbed flue gas in equivalent MW, based on the percentage of flue gas scrubbed by the FGD system(s).

GROWTH TRENDS

A historic review of the annual status of FGD technology in the utility industry is illustrated in Figure 1. This figure displays the operating and planned FGD capacity which existed at year's end for the period 1970 to 1983 (first quarter). Figure 1 reflects a significant growth in operating capacity since 1972. Since 1977, the capacity under construction has been fairly stable. The planned capacity peaked in 1980 and has been steadily declining since then.

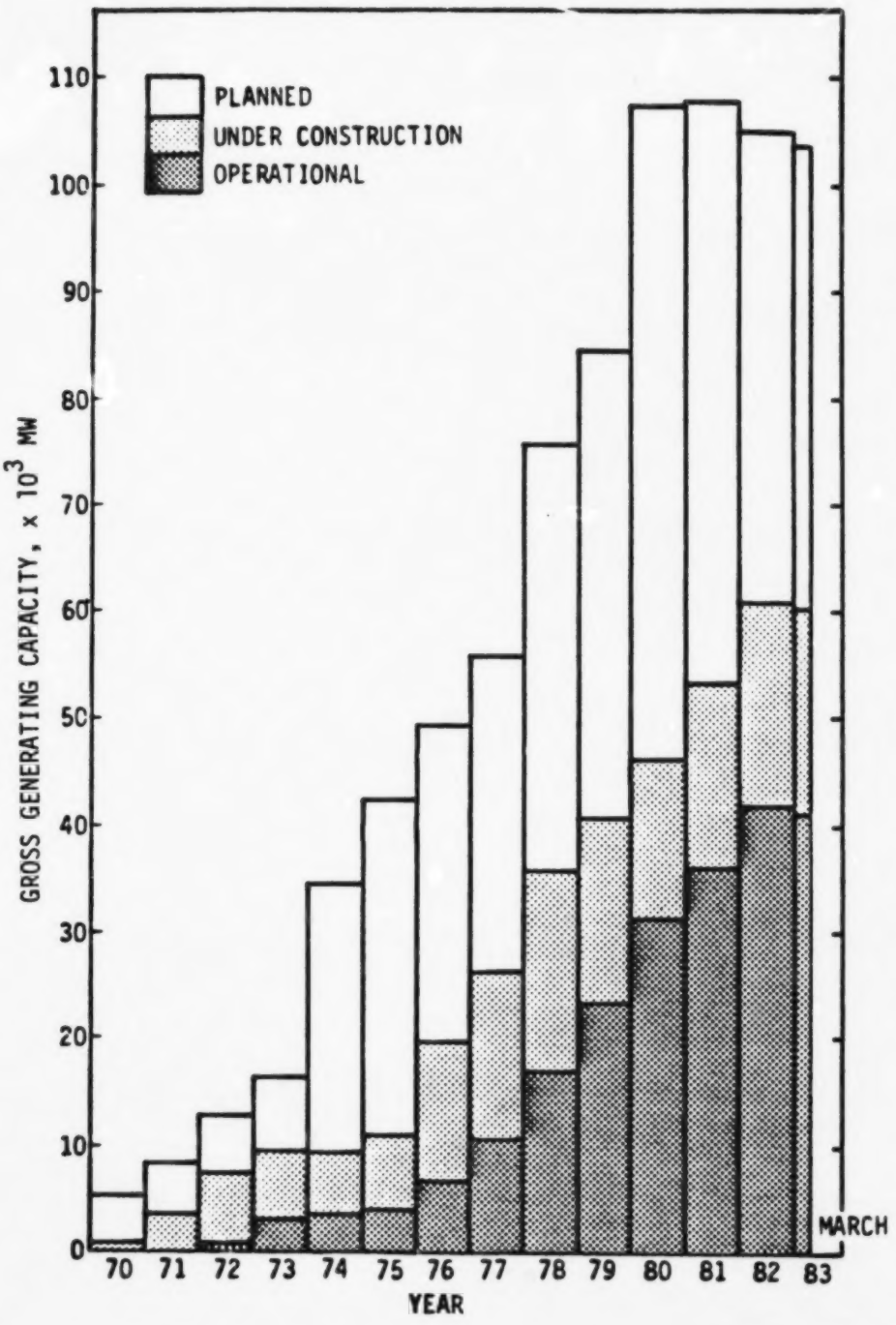

Figure 1. Historic review of the annual status of utility FGD.[2]

Figure 2 displays a comparison of actual coal-fired generating capacity and FGD capacity from 1975 through early 1983 and projections thereafter through 1991. Although the retirement of older units is taken into account, it significantly affects only the coal-fired capacity growth rate because FGD-controlled capacity represents primarily new power generating capacity. This accounts for the slightly greater slope of the FGD-controlled capacity plot.

Current projections indicate that the total power generating capacity of the U.S. electric utility industry will be approximately 799 GW by the end of 1991.[6] (This value reflects the loss resulting from the retirement of older units, which is considered to be approximately 2.52 GW by year end of 1991.[7]) Approximately 352 GW, or 44 percent of the 1991 total, is projected to be coal-fired units. The distribution of present (December 1982) and future (December 1991) power generation sources is shown in Table 5.

TABLE 5. POWER GENERATION SOURCES: PRESENT AND FUTURE[6]

	Coal	Nuclear	Oil	Hydro	Gas	Other	Total generating capacity, GW
December 1982	42%	11%	23%	12%	11%	1%	656
December 1991	44%	16%	19%	11%	9%	1%	799

It is interesting to note that the breakdown for the actual power produced by these sources during the past year (Table 6) differs somewhat from the power generating capacity shown in Table 5. This should be expected to fluctuate as the cost effectiveness of operating the various types of power plants changes with the U.S. economy.

TABLE 6. POWER PRODUCTION BY SOURCE[8]

	Coal	Nuclear	Oil	Hydro	Gas	Other	Total energy generated, GWh
January-December 1982	53%	13%	6%	14%	14%	0	2,241,211

Based on known commitments of utilities to FGD (as presented in Table 1) as well as other coal-fired generating capacity expected to require FGD (Figure 2), the current and projected percentages of electrical generating capacity controlled by FGD are shown in Table 7.

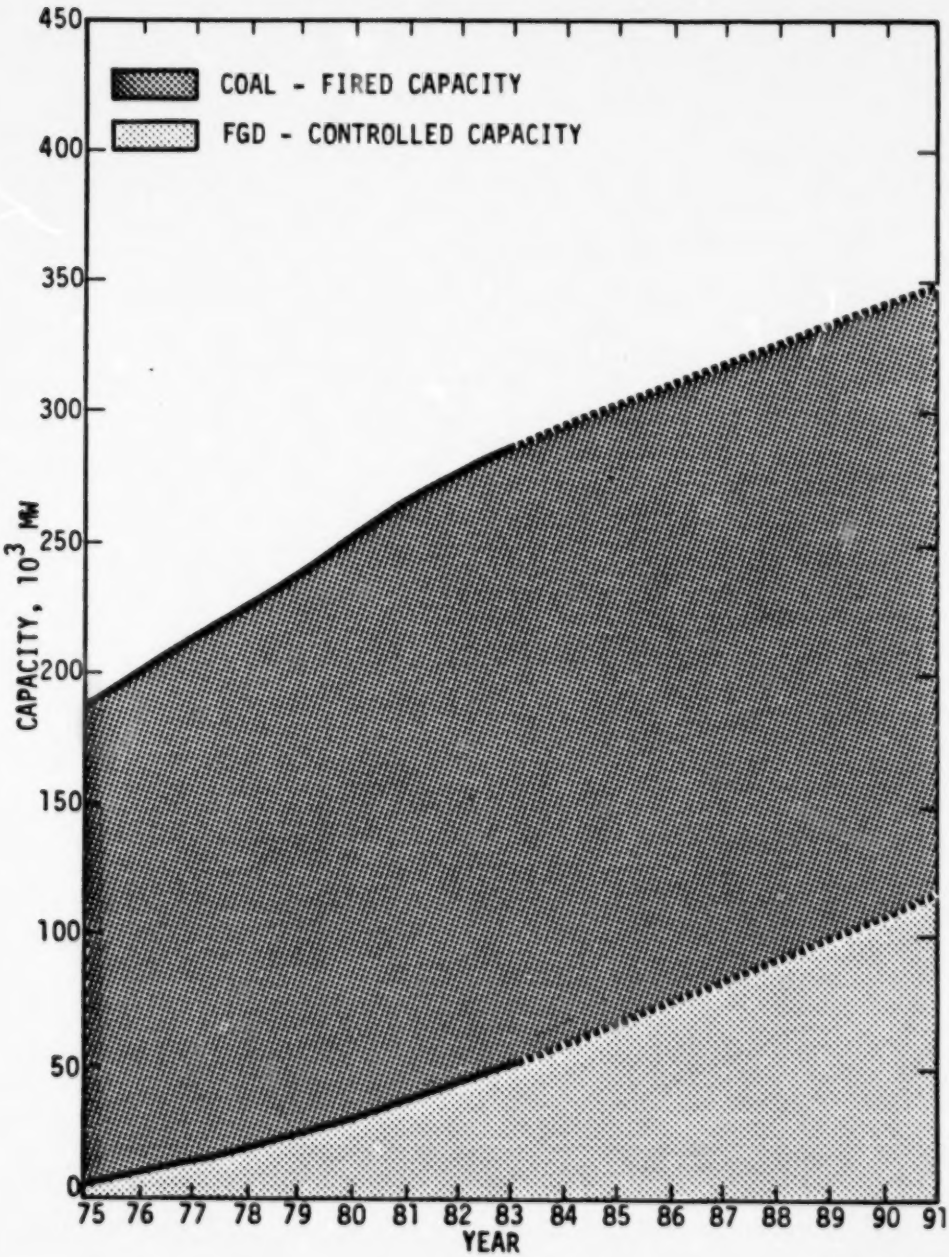

Figure 2. Actual and projected coal-fired generating capacity and FGD capacity, 1983.[2-7]

To show general FGD usage and projected usage trends, Table 8 gives both a current (March 1983) and projected (December 1999)

TABLE 7. FGD-CONTROLLED GENERATING CAPACITY: PRESENT AND FUTURE[2,6]

	Coal-fired generating capacity controlled by FGD, %	Total generating capacity controlled by FGD, %
March 1983	15.0	6.3
December 1991	32.2	14.0

TABLE 8. SUMMARY OF FGD SYSTEMS BY PROCESS[2]
(percentage of total MW)

Process	Byproduct	March 1983	December 1999
Throwaway product process			
Wet systems			
Lime		35	18
Limestone		48	45
Dual alkali		3	2
Sodium carbonate		3	3
Not selected[a]		0	3
Dry systems			
Lime		2	6
Sodium carbonate		1	<1
Salable product process			
Aqueous carbonate/ spray drying	Elemental sulfur	<1	<1
Lime	Gypsum	-	<1
Limestone	Gypsum	-	<1
Magnesium oxide	Sulfuric acid	2	<1
Wellman Lord	Sulfuric acid	5	2
Process undecided		-	19
Totals[b]		100	~100

[a]These systems are committed to a throwaway product process; however, the actual process is unknown at this time.

[b]These totals are proximate values since all numbers shown are listed to nearest whole number value.

breakdown of throwaway product systems versus salable product systems as a percentage of the total known commitments to FGD as of the end of the first quarter of 1983.

PERFORMANCE OVERVIEW

During the past several years, FGD has become the most commercially developed means of controlling SO_2 emissions from coal-fired boilers. FGD operating experience increases each year as more and more systems are placed in service. The FGD survey program has been monitoring the performance of the operating FGD systems and logging monthly operating parameters (e.g., boiler and FGD system operating hours, forced outage times, and scheduled outage times). With this operational information, system performance trends over the years can be analyzed and reviewed.

One important criterion for the evaluation of FGD performance is system dependability. We have developed a number of dependability parameters to measure this index for various situations, conditions, and information-reporting formats. Of these parameters, "availability" seems to be the parameter most universally accepted and understood. In context of FGD, system availability is defined as the hours the FGD system is available for operation (whether operated or not) divided by hours in the period. Period hours are usually equal to hours in a month.

Availability data for operating FGD systems have been collected through the Utility FGD Survey program on a monthly basis. The monthly data were used to calculate the average annual availabilities for each system.

Figures 3 and 4 are the median analyses of the annual average availabilities for all FGD systems (for which data are available), broken down for low-, medium-, and high-sulfur coals.* Median analyses were based on data from the period of 1978 through 1982 (5-year period). In each case, the availability points were plotted and the median was determined.

---

* The coal sulfur content ranges are defined as less than 1 percent, 1 through 3 percent, and greater than 3 percent for low, medium, and high, respectively.

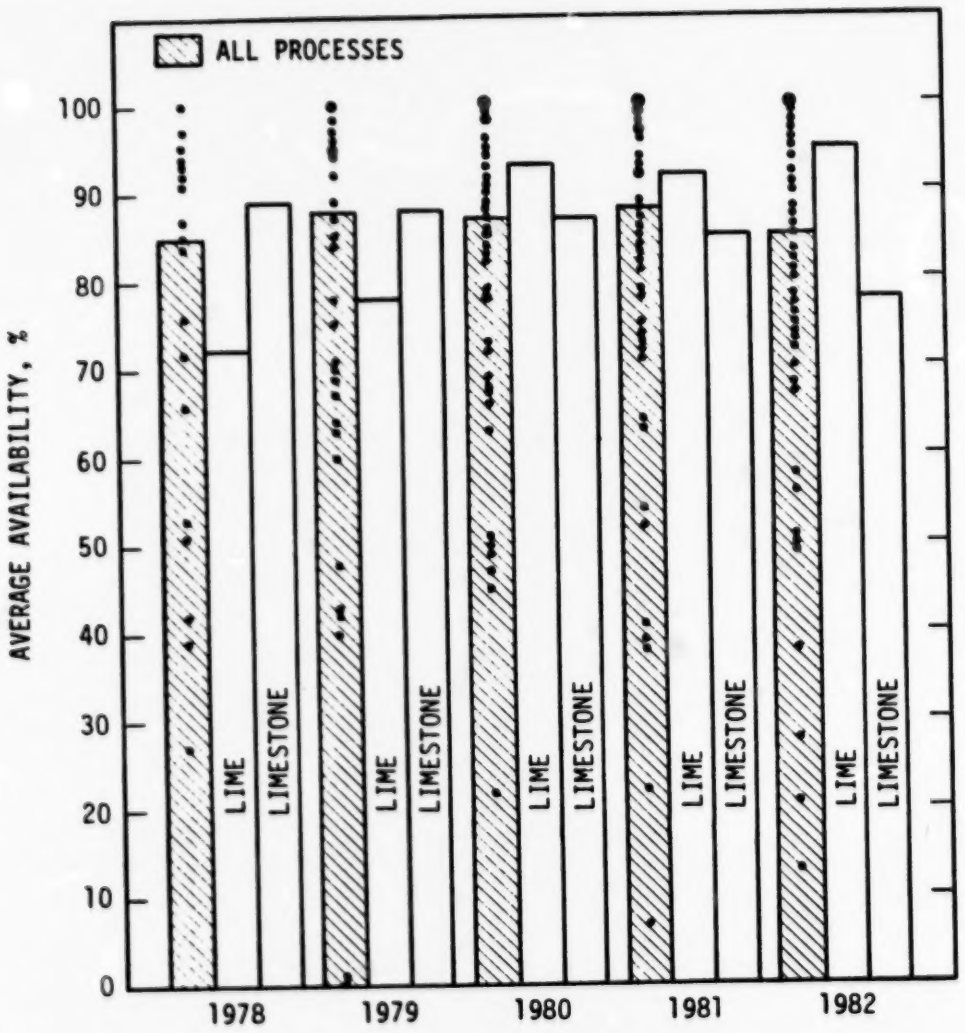

Figure 3. Median analysis of the annual availability for coal-fired FGD systems.[2]

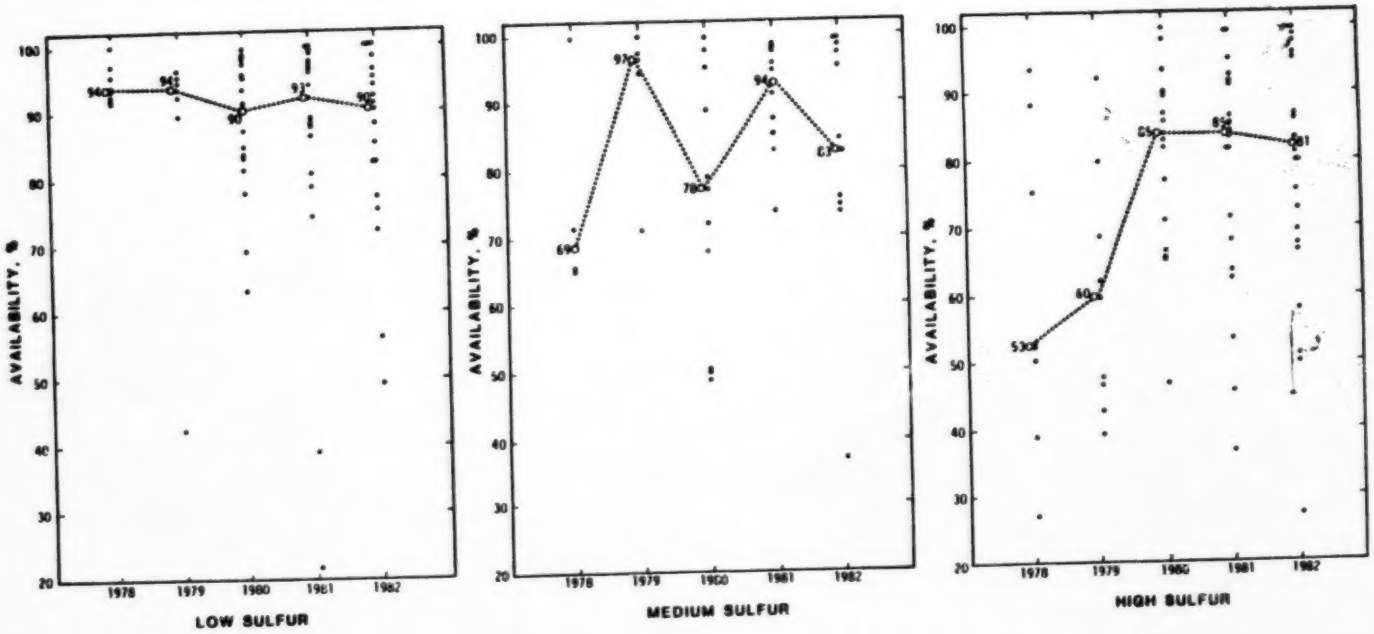

Figure 4. Median availability analysis by coal sulfur content.

As can be seen from these figures, low sulfur systems show the steadiest median of the three, with the median changing only a few percentage points. The high sulfur systems exhibit the most dramatic improvement over the period, as well as exhibiting a relatively constant trend for the past three years. The medium sulfur coal systems also exhibit significant improvement; however, two fluctuations are observed for 1980 and 1982.

COSTS OVERVIEW

Capital and annual cost data for operational FGD systems have been obtained continuously under the utility survey program since March 1978. Costs for each system are obtained directly from the utilities and then itemized by individual FGD cost element. The itemized costs are then adjusted to a common basis to enhance comparability. This adjustment is made by using factors for estimating costs not given by the utilities and by using cost index factors to express all costs in constant year dollars (mid-1981). All adjusted cost data and computations are reviewed and verified with the appropriate utility before publication.

The cost adjustment procedure is summarized below.

Capital Costs

- All costs associated with control of particulate matter emissions are excluded.
- Capital costs for modifications necessitated by installation of an FGD system are added if they were not included in the reported costs.
- Sludge disposal costs are adjusted to reflect a 20-year life span for retrofit systems and a 30-year life span for new systems.
- Any unreported direct and indirect costs incurred are estimated and included.
- All capital costs are expressed in mid-1981 dollars.
- All capital costs reflect the gross generating capacity of the unit.

Annual Costs

- Direct costs that were not reported are estimated and added.
- Overhead and fixed costs that were not reported are estimated and added.

- All annual costs are expressed in mid-1981 dollars.
- All annual costs are based on a 65 percent capacity factor and the net generating capacity of the unit.

Table 9 summarizes both reported and adjusted costs for all operational FGD systems on which cost data were obtained. This table also summarizes the results, by application and by process category. Table 10 lists the results by process type. Table 11 provides a plant-by-plant listing of the reported and adjusted costs for the operational FGD systems addressed in this study.

FGD technology has been available for service on utility boiler flue gas for approximately 50 years. The most significant period of development has occurred since 1966 when limestone injection/tail-end wet scrubbing was first introduced in the United States and tested on coal-fired boiler flue gas. Since that time, there have been more than 125 FGD systems operated on utility boilers, primarily as commercial facilities and secondarily as experimental prototype or demonstrational facilities.

The 106 units presently in service on coal-fired utility boilers in the United States represent approximately 42,000 MW of installed gross generating capacity. Another 105 units representing 62,000 MW of installed gross generating capacity are planned for future service. Comparison of FGD with respect to the utility industry as a whole reveals that approximately 15 percent of the installed coal-fired power generating capacity is operating with FGD systems. This level is projected to grow to 32 percent during the next 10-year period.

Lime/limestone slurry processes producing a waste product for disposal are still largely preferred by the utility industry over the other commercially available processes such as dual alkali, sodium sulfite/thermal regeneration (Wellman-Lord), and magnesium oxide. The most significant development in process selection is the ready acceptance of dry scrubbing technology, which is largely relegated to low-sulfur western coal applications.

Overall, the performance of FGD with respect to system availability tends to show steady improvement. Lime and dual alkali processes have significantly improved the technology's performance on high-sulfur coal.

The capital and annual costs for a significant portion of the commercial population reflect an overall cost of approximately $119/kW and 8 mills/kWh, respectively. These figures apply to a wide variety of systems that represent different processes, generation of development, applications, and severity of duty for units in commercial service from 1972 to 1981.

TABLE 9. CATEGORICAL RESULTS OF THE REPORTED AND ADJUSTED CAPITAL AND ANNUAL COSTS FOR OPERATIONAL FGD SYSTEMS[9]

	Reported				Adjusted			
	Capital		Annual		Capital		Annual	
	Range, $/kW	Average, $/kW	Range, mills/kWh	Average, mills/kWh	Range, $/kW	Average, $/kW	Range, mills/kWh	Average, mills/kWh
All	23.7-213.6	80.2	0.1-13.0	2.3	38.3-282.2	118.8	1.6-20.8	7.6
New	23.7-213.6	80.4	0.1-5.5	1.7	38.3-263.9	110.8	1.6-14.6	6.8
Retrofit	29.4-157.4	79.7	0.5-13.0	4.5	60.4-282.2	139.3	4.3-20.8	9.7
Saleable	132.8-185.0	153.1	13.0-13.0	13.0	254.6-282.2	271.6	16.7-20.8	18.1
Throwaway	23.7-313.6	75.8	0.1-11.3	2.1	38.3-263.9	110.9	1.6-17.6	7.0

TABLE 10. ADJUSTED CAPITAL AND ANNUAL COSTS[9] FOR OPERATIONAL FGD SYSTEMS BY PROCESS TYPE

	Reported				Adjusted			
	Capital		Annual		Capital		Annual	
	Range, $/kW	Average, $/kW	Range, mills/kWh	Average, mills/kWh	Range, $/kW	Average, $/kW	Range, mills/kWh	Average, mills/kWh
Limestone	2.37-170.4	67.9	0.1-7.8	1.6	38.3-194.3	98.9	1.6-14.6	6.1
Lime	29.4-213.6	81.8	0.3-11.3	3.2	60.4-210.0	116.5	4.0-17.6	8.1
Dual alkali	47.2-174.8	97.8	1.3-1.3	1.3	87.8-263.9	146.7	5.0-13.9	8.7
Lime/alkaline flyash	43.4-173.8	93.9	0.4-5.4	2.1	52.5-184.4	122.8	3.0-14.1	7.2
Sodium carbonate	42.9-100.8	69.2	0.2-0.5	0.4	87.1-150.9	110.9	5.8-7.4	6.4
Wellman-Lord	132.8-185.0	153.1	13.0-13.0	13.0	254.6-282.2	271.6	16.7-20.8	18.1
Limestone/alkaline flyash	49.3-49.3	49.3	0.8-0.8	0.8	102.6-102.6	102.6	5.4-5.4	5.4

TABLE 11. REPORTED AND ADJUSTED CAPITAL AND ANNUAL COSTS FOR OPERATIONAL FGD SYSTEMS

	Reported				Adjusted			
	Capital	$/kW	Annual	Mills/kWh	Capital	$/kW	Annual	Mills/kWh
Alabama Electric								
Tombigbee 2	6,971,100	27.4	434,929	0.33	9,756,200	38.3	4,249,650	3.18
Tombigbee 3	6,992,100	27.4	434,929	0.33	9,756,200	38.3	4,249,650	3.18
Arizona Electric Power								
Apache 2	8,148,069	41.8	51,784	0.10	13,171,700	67.5	3,739,900	3.75
Apache 3	7,214,062	37.0	51,784	0.10	11,661,900	59.8	3,739,900	3.75
Arizona Public Service								
Cholla 1	6,550,000	52.0	NA	NA	10,246,100	81.3	4,608,800	4.79
Cholla 2	44,352,000	168.0	1,003,568	0.75	42,787,600	162.1	10,998,300	8.22
Central Illinois Light								
Duck Creek 1	31,125,000	74.8	10,851,000	5.04	55,001,000	132.2	12,433,100	5.78
Central Illinois Public Service								
Newton 1	107,831,000	174.8	NA	NA	162,847,600	263.9	45,624,900	13.94
Colorado Ute Electric								
Craig 1	38,613,900	86.5	462,600	0.53	48,179,000	105.9	12,148,300	5.33
Craig 2	32,810,900	73.5	1,128,400	0.48	41,070,100	90.3	10,382,700	4.56
Columbus & Southern Ohio Electric								
Conesville 5	20,663,500	90.3	8,670,530	5.52	40,857,200	99.4	14,475,100	6.78
Conesville 6	20,663,500	90.3	8,670,530	5.52	40,857,200	99.4	14,475,100	6.78
Cooperative Power Association								
Coal Creek 1	23,650,000	43.4	1,166,200	0.41	28,633,100	52.5	8,414,350	2.99
Coal Creek 2	23,650,000	43.4	1,166,200	0.41	28,633,100	52.5	8,414,350	2.99
Duquesne Light								
Elrama 1-4	61,320,000	120.2	21,027,451	7.18	95,755,400	187.8	35,731,700	12.89
Phillips 1-6	52,055,000	127.0	18,301,000	11.00	86,097,500	210.0	35,731,700	17.65
Indianapolis Power & Light								
Petersburg 3	55,820,000	104.9	NA	NA	86,227,500	162.1	28,565,000	9.74
Kansas City Power & Light								
Hawthorn 3	3,220,000	29.4	346,441	1.15	6,909,850	62.8	2,912,100	5.25
Hawthorn 4	3,220,000	29.4	346,441	1.15	6,909,850	62.8	2,912,100	5.25
LaCygne 1	46,900,000	53.7	8,060,047	5.38	87,498,400	100.1	52,735,300	11.29
Kansas Power & Light								
Jeffrey 1	27,306,900	37.9	321,000	0.11	39,710,500	55.9	9,353,200	2.42
Jeffrey 2	26,458,800	37.8	949,900	0.29	28,840,100	41.2	6,396,400	1.65
Kentucky Utilities								
Green River 1-3	3,966,155	62.0	364,005	5.20	7,510,600	117.8	3,754,800	10.99
Louisville Gas & Electric								
Cane Run 4	12,647,000	86.6	960,301	1.29	21,882,500	115.2	6,422,400	6.20
Cane Run 5	13,759,000	68.8	763,443	0.92	20,476,600	102.4	5,784,300	5.30
Cane Run 6	20,594,900	71.5	NA	NA	25,290,600	87.8	11,073,000	7.23
Mill Creek 1	17,661,500	65.0	NA	NA	21,627,800	60.4	8,107,100	4.26
Mill Creek 3	18,046,880	42.6	321,463	1.25	29,163,000	66.0	9,636,200	4.03
Paddy's Run 6	4,320,000	61.7	NA	NA	9,307,300	133.0	4,430,300	12.25
Minnesota Power & Light								
Clay Boswell 4	86,900,000	173.8	18,844,512	5.38	102,165,300	184.4	40,437,300	14.09
Minnkota Power								
Milton R. Young 2	44,119,800	100.3	754,445	0.53	68,487,500	155.7	14,066,000	6.44
Monongahela Power								
Pleasants 1	81,452,400	119.1	5,532,800	1.46	104,562,000	152.9	27,951,300	7.94
Pleasants 2	81,452,400	119.1	5,532,800	1.46	104,562,000	152.9	27,951,300	7.94
Montana Power								
Colstrip 1	36,500,000	101.4	6,128,000	2.97	52,519,850	145.9	15,642,050	8.27
Colstrip 2	36,500,000	101.4	6,128,000	2.97	52,519,850	145.9	15,642,050	8.27
Nevada Power								
Reid Gardner 1	5,363,375	42.9	251,514	0.46	10,891,350	87.1	3,617,450	5.78
Reid Gardner 2	5,363,375	42.9	251,514	0.46	10,891,350	87.1	3,617,450	5.78
Reid Gardner 3	12,899,160	100.8	131,824	0.23	18,866,173	150.9	4,637,163	7.40
Northern Indiana Public Service								
Bean H. Mitchell 11	18,192,840	157.4	2,414,589	13.02	29,431,808	254.6	11,129,239	20.79
Northern States Power								
Sherburne 1	34,882,020	69.3	2,716,769	0.75	73,854,486	102.6	21,018,195	5.43
Sherburne 2	34,882,020	69.3	2,716,659	0.75	73,854,486	102.6	21,018,195	5.43
Pacific Power & Light								
Jim Bridger 4	49,643,000	90.3	NA	NA	66,113,736	118.6	19,681,160	6.81
Pennsylvania Power								
Bruce Mansfield 1	110,639,000	120.7	9,979,900	3.28	132,234,039	144.2	53,122,918	11.31
Bruce Mansfield 2	110,639,000	120.6	9,979,900	3.28	132,234,039	144.2	53,122,918	11.31
Bruce Mansfield 3	195,857,200	213.6	11,575,300	3.11	166,043,400	181.1	48,255,200	10.27
Public Service of New Mexico								
San Juan 1	47,944,400	132.8	NA	NA	100,333,473	277.9	29,836,802	16.69
San Juan 2	47,985,000	137.1	NA	NA	98,777,569	282.2	29,423,764	16.89
Salt River Project								
Coronado 1	32,624,500	79.4	1,788,000	0.85	35,560,700	86.5	15,339,100	7.70
Coronado 2	32,624,500	79.4	1,788,000	0.85	35,560,700	86.5	15,339,100	7.70
South Carolina Public Service								
Winyah 2	6,646,098	23.7	527,000	0.29	13,148,872	47.0	2,697,896	1.84
Winyah 3	10,742,500	38.4	NA	NA	18,646,700	66.6	6,926,700	4.83
South Mississippi Electric Power								
R. D. Morrow, Sr. 1	10,896,000	53.7	NA	NA	24,047,200	118.5	7,115,990	6.94
R. D. Morrow, Sr. 2	10,896,000	53.7	NA	NA	24,047,200	118.5	7,115,990	6.94
Southern Illinois Power								
Marion 4	18,200,930	87.9	869,453	0.98	20,906,447	120.8	7,107,823	7.75
Southern Indiana Gas & Electric								
A. B. Brown 1	12,496,800	47.2	1,860,565	1.30	23,414,148	88.4	7,094,130	4.98
Springfield City Utilities								
Southwest 1	16,744,500	86.3	778,749	1.20	27,822,607	143.4	8,082,239	8.21
Springfield Water, Light & Power								
Ballman 3	34,923,800	178.4	4,381,500	4.68	39,829,200	191.3	15,913,700	14.56
Tennessee Valley Authority								
Widows Creek 8	47,900,000	87.1	14,576,000	7.76	86,968,828	158.1	21,379,073	7.28
Utah Power & Light								
Hunter 1	24,400,000	86.7	NA	NA	32,294,620	75.1	10,614,532	4.66
Hunter 2	29,880,000	60.2	1,872,600	0.32	31,225,000	72.6	10,355,780	4.55
Huntington 1	2,700,000	63.0	2,946,400	1.27	38,698,607	90.0	13,411,652	5.89

REFERENCES

1. Kaplan, N., and F. T. Princiotta. Utility Flue Gas Desulfurization Technology and Costs. Presented at the 10th Annual Illinois Energy Conference. October 13-15, 1982, Chicago, IL.

2. U.S. Environmental Protection Agency. Flue Gas Desulfurization Information System (FGDIS). Computerized Data Base. Industrial Environmental Research Laboratory, Research Triangle Park, NC. (Access to FGDIS can be obtained through Walter Finch, NTIS, 5285 Port Royal Road, Springfield, VA 22161.)

3. U.S. Department of Energy. Inventory of Power Plants in the United States, DOE/RA-001, December 1977. Office of Utility Project Operations.

4. U.S. Department of Energy. Inventory of Power Plants in the United States - December 1979. Energy Information Administration. DOE/EIA-0095(79), June 1980.

5. U.S. Department of Energy. Inventory of Power Plants in the United States - 1980 Annual. Energy Information Administration. DOE/EIA-0095(80), June 1981.

6. U.S. Department of Energy. Inventory of Power Plants in the United States - 1981 Annual. Energy Information Administration. Office of Coal, Nuclear, Electric, and Alternate Fuels. DOE/EIA-0095(81), September 1982.

7. Personal communication from Mr. Skeer, Office of Policy Planning and Analysis, U.S. Department of Energy, August 1983.

8. U.S. Department of Energy. Energy Information Administration. Office of Coal, Nuclear, Electric, and Alternate Fuels. Electric Power Monthly, DOE/EIA-0226(83/01), January 1983.

9. Smith, M. P., M. Melia, and N. Gregory. EPA Utility FGD Survey: July-September 1981, EPA-600/7-81-012e, NTIS No. PB 82-231150, U.S. EPA, Industrial Environmental Research Laboratory, Research Triangle Park, NC, December 1981. [Issued every 3 months. Referenced report is most recent.]